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QUESTIONS AND ANSWERS ABOUT THE NATURE AND CAUSES OF THE NATURAL GAS SHORTAGE

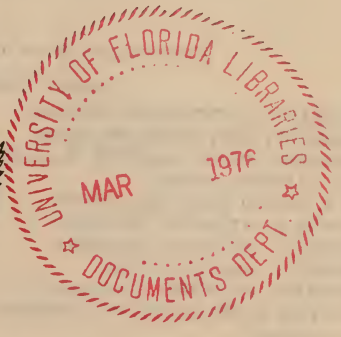
BY THE STAFF

OF THE

SUBCOMMITTEE ON OVERSIGHT AND INVESTIGATIONS

OF THE

COMMITTEE ON INTERSTATE AND FOREIGN COMMERCE HOUSE OF REPRESENTATIVES



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This Report is based on hearings by the Oversight and Investigations Subcommittee and by the Energy and Power Subcommittee and on Congressional Reference Service analyses by John Jimison and Lawrence Kumins, as well as from studies by the General Accounting Office and the Federal Power Commission, among others.

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Questions and Answers About the Nature and Causes of the the Natural Gas Shortage

Question 1. Is there a natural gas shortage, and if so, how serious is it?

Answer. The nation uses natural gas for about one-third of its energy needs. Since 1968, the natural gas industry, according to nation-wide figures, found less gas than it produced. The result has been a net decline in the nation's total reserves. Currently, there is a surplus of gas in the intrastate market, but supply has declined sharply in the interstate market while demand has continued to rise.

The Federal Power Commission estimated that the nation-wide shortage of natural gas will be 2.9 trillion cubic feet (Tcf) from April 1, 1975 to March 31, 1976. Curtailment for that period was projected by the FPC at 19.30 percent of pipelines' "firm requirements." [1]

However, more recent information compiled by the Congressional Office of Technology Assessment indicates that the shortage this winter may not be as severe as the FPC predicted.[2]

According to OTA, the projected supply for the period April 1, 1975 to March 31, 1976, is 12.1 Tcf. Although real demand for natural gas for that period is not precisely known, it can be estimated to be about 13.1 Tcf amounting to a shortfall of about 1.0 Tcf.

In October, the Federal Energy Administration reported projected distributor curtailments in 21 key States of 1.2 Tcf this winter. This would have been a 314 Bcf, or 37 percent, increase over last winter.

On December 25, FEA published a revised estimate. FEA's latest survey of large natural gas distributors in the same 21 States shows total curtailments reduced to 1.0 Tcf this winter. This is a 140 Bcf, or 16 percent, increase over last winter.

Question 2. Was the natural gas shortage caused by regulation?

Answer. The natural gas industry claims that the prices set by the Federal Power Commission for the last 20 years are too low to elicit sufficient investment by producers to maintain adequate reserve levels, and that the artificially low price stimulated heavy demand for this fuel that quickly took up available supplies. Although this interpretation sounds plausible, it does not jibe with the facts. The shortage derives from the rapid growth of major gas consuming markets in proximity to the producing fields. Much of that growth, moreover, resulted from aggressive promotional campaigns by producers and distributors to convince the public that gas was a low-cost, clean and reliable energy source. Neither were the prices set by the

[1] United Gas Pipeline, FPC Report, "Requirements and Curtailments of Interstate Pipeline Companies Based on Form 16 Reports Required to be filed on Apr. 30, 1975," June 1975, at 2.

[2] U.S. Congress, Office of Technology Assessment, An Analysis of the Impacts of the Projected Natural Gas Curtailments for the Winter 1975–76, Nov. 4, 1975, at 16.

FPC unduly low. Annual production and total reserves increased rapidly until 1968, when they began to decline. Interestingly, 1968 was the date that the Supreme Court affirmed the authority of the FPC to set cost-based area rates and saw establishment of a wellhead-pricing system in which there is an inverse relationship between wellhead price and amount of reserve additions. This means that all other things being equal, the lower the reserve additions, the higher the FPC set the wellhead price. The higher the reserve additions, the lower the FPC set the wellhead price. In the 1971 Southern Louisiana Area Rate Proceeding, producers themselves said that 26 cents per Mcf would be an adequate price to stimulate additional production. The FPC granted the rate settlement requested, but reserve additions have continued to decline in Southern Louisiana as well as in other producing areas. Regulated prices have risen at a rate of about 30 percent per year and now are at twice the level requested by the industry for 1975 in the 1971 case. Producers now condemn a suggested ceiling price of 75 cents pre Mcf as "inadequate," knowing that gas prices in excess of $2.00 per Mcf could be obtained in the absence of FPC controls. There is no credible evidence to suggest that removal of FPC regulation would have delayed or prevented the shortage of natural gas.[3]

Question 3. Do natural gas producers have an economic incentive to withhold gas from the market?

Answer. Although the incentive to withhold under continued regulation in anticipation of higher FPC rates is not strong in view of the fact that a commitment of gas at one area price no longer locks the producer into receiving that price for the entire term of the contract but rather allows for biennial rate reviews, there is considerable incentive to withhold in anticipation of deregulated prices.

Natural gas prices following deregulation are likely to be much higher even than the current unregulated intrastate market prices due to increased demand from the currently unsatisfied interstate market. Deregulated prices in excess of $3 per Mcf are quite possible after deregulation as compared with current average intrastate prices of $1.50 per Mcf. Prices of $3 to $5 per Mcf promise much greater returns over the life of a contract than current prices.[4] This would furnish substantial incentive to withhold or to slow down production rates.

In order to compare the profitability of immediate production at FPC rates with the profitability of delayed production at deregulated rates, John Jimison, Analyst, Library of Congress, employed discount factors of 10 percent and 15 percent to yield the present values of future revenues. He used a hypothetical gas field containing about 100 billion cubic feet (Bcf) of reserves and calculated production on a basis of ten years at ten Bcf per year. Jimison determined the net present value of the future revenues from the field for each of the alternate discount factors by subtracting from the present value of the total future revenues the total present costs of development for offshore and onshore gas. Thus he calculated the net present value of the producing field for a regulated price scenario and a deregulated price scenario, adjusting for the effects of withholding production for as much as ten

[3] Jimison, John W., Analyst, Environmental Policy Division, Congressional Research Service, "Deregulation of Natural Gas: the Pros and Cons," at CRS 3–9. [Hereinafter referred to as the Jimison Study.]

years in the future. Jimison concluded that the withholding is theoretically profitable for as long as five years for both onshore and offshore gas if the discount factor is 15 percent.

Jimison concludes:

> The foregoing hypothetical analysis suggests that a natural gas producer with a typical gas field has a strong motivation not to commit that gas to market at current regulated prices (even assuming that those prices will increase at 30 percent per year and that he will receive the increased prices as they are decided upon) because committing his field at deregulated prices is more profitable even after a four-year wait. . . . Only natural gas producers themselves have access at present to the underlying information on costs and findings which could result in truly definitive examination of the profitability of withholding . . . While specific actual inputs might lead to some variance of the results of this analysis, its general conclusion that withholding in anticipation of deregulated prices is profitable under some circumstances seems valid.[5]

Question 4. Is there evidence of withholding?

Answer. Natural gas can be withheld from production in many ways. It is not merely a matter of the producers' refusal to produce natural gas from wells that are completed and capped. Withholding of natural gas can result from any action by a producer to delay production of gas from a potential sources in order to sell at higher prices later. If a natural gas resource is thought definitely to exist but is not explored in order to explore it later, withholding of gas may be involved. If exploration wells have determined that natural gas is present in economically productible quantities in a field, but production wells are not being drilled in a timely manner or the exploratory success has been hidden, withholding may be alleged. If natural gas has been found and partially developed but proved reserve data made public significantly understate the amount of reserves in place, this may be considered a form of withholding. If production from a lease has unaccountably fallen below minimum contract quantities, withholding may be occurring. If unduly large amounts of gas available in reservoirs are being retained for future sales under a contract, when current shortages are unsatisfied, withholding may be involved.[6]

There is evidence to suggest that most—if not all—of these types of withholding are occurring:

(a) Withholding of natural gas can result from any action by a producer to delay production of gas from a potential source in order to achieve higher prices later:

> Evidence of speculative withholding emerged when the Subcommittee on Oversight and Investigations found serious discrepancies between testimony before the Federal Power Commission and the facts about the reasons for the curtailments last winter to Transco, on interstate pipeline. Mitchell Energy, a large independent producer, contracted with Transco to deliver gas in the Gulf of Mexico by November 1—well in advance of the '74–'75 winter heating season. However, the gas was not brought on line until seven months later, and the loss to Transco was at least 2.4 billion cubic feet.

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[4] Jimison Study, supra n. 3, at CRS–10.
[5] Id. at 24.
[6] Jimison, John W., "The Controversy Over Withholding of Natural Gas Production" (Parts I and II of four parts), Congressional Research Service, November 21, 1975, at 2.

At the FPC fact-finding proceeding, a Mitchell official testified that there were no records concerning the delay, that a month was lost due to bad weather in the Gulf, and that the fabricator of the production equipment had wasted time looking for used rather than new equipment. Whereas the facts—as uncovered by the Subcommittee—reveal that there were continuing design changes in the production equipment By Mitchell and over 100 documents in Mitchell's files relating to the delay; that only six days—not a month—were lost to bad weather; and that Mitchell's contract with the fabricator called for the use of used equipment.

What was Mitchell's motive? On June 21, 1974, the FPC issued Order 699 eliminating area rates and setting a national rate of 43 cents Mcf. Petitions were filed with the FPC by industry saying the rate was too low. On August 2, the FPC announced it would reconsider, and the assumption within the industry was that it would be reconsidered upwards. On December 4, 1974, the FPC issued Order 699–H raising the wellhead price of gas to 51 cents per Mcf for gas from wells completed after January 1. By bringing the gas on line after January 1, at the higher rate, Mitchell could gain $496,000. Mitchell Vice President Sidney Walker's testimony before the Federal Power Commission concerning delays in delivery of gas to Transco was reviewed at the request of the Subcommittee by former Counsel to the Senate Select Committee on Presidential Campaign Activities, Professor Samuel Dash, who has concluded that it involved a clear-cut case of perjury and obstruction of justice. Chairman Moss has requested that Attorney General Levi personally condust an in-depth review of the case.

(b) If a natural gas resource exists, but is not explored in order to explore it later, withholding of gas may be involved:

The *Oil and Gas Journal* noted in an article dated June 23, 1975, only 48 of 1068 Gulf of Mexico tracts leased since 1970 are producing. Many of those leases have not even been explored.

The U.S. Geological Survey has identified more than 60 leases that have been held for two years or more for which not a single exploratory well has been drilled.

(c) If exploration wells have determined that natural gas is present in economically productible quantities in a field, but production wells are not being drilled in a timely manner or exploratory success has been hidden, withholding may be involved.

The deliverability of natural gas from many U.S. fields has fallen precipitously, threatening severe curtailments of supplies and substantial economic disruptions in many areas of the nation. The Subcommittee on Oversight and Investigations' study of deliverability problems was undertaken to determine the reasons for the decline in production and to explore ways in which deliverability can be increased.

In order to examine the deterioration of natural gas deliverability, the Subcommittee reviewed data on more than forty fields in the Gulf Coast area. By requesting information and

through the issuance of subpoenas, it was possible to obtain deliverability forecasts prepared by pipeline companies for those fields. Analysis of forecasts, production data, and other documents enabled the Subcommittee to identify many fields exhibiting symptoms of the pervasive problem of rapidly declining production. Subpoenas were then issued to producers for documents relating to the production and development of the Garden City and Bastian Bay fields in South Louisiana. After reviewing the documents, the Subcommittee staff interviewed the pipeline and producer personnel most familiar with Garden City to gain further information on the status of the field. The Subcommittee on September 5, 1975, heard testimony in executive session from officials of Quintana Petroleum Corporation, which operates the field, and Columbia Gas, which purchases gas at Garden City for resale in interstate commerce. Its release was approved by the Subcommittee on October 28, 1975.

Garden City

Garden City is a large natural gas field in onshore South Louisiana. The field is produced by Exxon Corporation and Quintana Petroleum Corporation. For nearly 20 years, this field has produced substantial quantities of natural gas—122 billion cubic feet in 1970. However, production from Garden City has been declining. This in itself is not remarkable since the field is no longer young, but the field has been declining much more rapidly than expected. Production at Garden City has been falling at a rate in excess of 30 percent per year, causing severe supply problems for the Columbia Gas System and contributing to curtailments in several states.

Major Subcommittee findings contained in the Garden City report [7] include:

Production from the field has been declining at an annual rate in excess of 30 percent.

The present rate of decline is substantially greater than projected during 1970–73 by either the pipeline or producers and is substantially greater than the historical norm of 15 percent for South Louisiana fields.

The producers failed to diligently undertake the work projects necessary to maintain deliverability from the field and to establish production from untapped reservoirs.

In at least one instance, the operator indefinitely deferred undertaking an economically feasible work project that would have significantly increased gas supplies in anticipation of future increases in natural gas prices. (See Appendix A)

A significant portion of the field's reserves are reservoirs from which there never has been any production.

Negotiations to drill new wells have been in progress since September 1974.

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[7] Report by the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce, "Natural Gas Supplies: Declining Deliverability at Garden City, La.," October 1975, at 2.

Officials of Columbia Gas found that the operator has restricted the producing capability of the field.

Bastian Bay

Following an investigation of the Bastian Bay field in onshore Louisiana, the Subcommittee concluded that Getty Oil Company and Tenneco, Inc., the two producers of the field, had not undertaken sufficient drilling to maintain natural gas deliverability.

Consequently, the field may be produced over a period of 62 years, instead of the originally contemplated 20 to 25 years or the industry standard of 15 to 20 years.

Evidence in support of this conclusion includes the following:[8]

> In June 1974, Getty engineers identified three gas reservoirs containing (as of January 1974, according to Getty) a total of 312 billion cubic feet of gas (more than half the remaining reserves) where they recommended accelerated depletion. (See Appendix C) In spite of this recommendation, Tenneco has declined to approve substantial new drilling and only one new wellbore has been drilled in the last three years.
>
> Tenneco has declined to approve a new well into the "X" Reservoir (Fault Block B) containing 73 billion cubic feet (as of January 1974 by Getty's analysis) and currently produced by only two wells even though Getty has indicated that accelerated depletion is necessary and has proposed a new well since May 1974.
>
> Tenneco has declined to approve a well into a currently non-producing reservoir (the "V" Reservoir, containing 12.5 billion cubic feet according to Getty) which has been proposed by Getty since January 1974.
>
> Getty Oil Company has not undertaken a study of additional new wells (which would increase deliverability) as recommended by its petroleum engineer in charge of the field in June 1974.

Getty has been unwilling, the study found, to commit substantial sums to accelerated production, although it filed for and received from the FPC four separate increases for wells or recompletions started on or after January 1, 1973. As a result of these price increases, Getty estimates that it will receive revenue of about $1.7 million as opposed to about $775,000 over the life of those wells at the old rate.

The reason for Getty's reluctance to accelerate production, despite these additional revenues, may be, as the report suggests, because Getty has an incentive to maximize the amount of gas which remains for recovery after June 22, 1982, when its contract with United Gas Pipeline ends. Getty has predicted a price of $1.80 per Mcf for gas by 1982 (or $1.21 in constant dollars) even assuming continued FPC regulation.

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[8] Report by the Subcommittee on Oversight and Investigations of the Committee on Interstate and Foreign Commerce, "Natural Gas Supplies: Declining Deliverability at Bastian Bay Field, La.", November 1975 at 3.

Evidence that Getty as well as other producers may be holding out for a higher price is contained in an internal Getty document. (see Appendix B) In the event of deregulation, the study projects an immediate 281 percent increase in the price of new natural gas from the current 52 cents per thousand cubic feet to $2.37 (in constant dollars) per thousand cubic feet.

On the basis of its findings with respect to both fields, the Subcommittee recommended that the Federal Power Commission immediately commence enforcement proceedings and issue appropriate orders requiring natural gas producers to undertake work projects and to take other steps necessary to maintain deliverability at contractual and certificate levels in accordance with producers' legal obligations.

(*d*) If natural gas has been found and partially developed, but proven reserve data made public significantly understate the amount of reserves in place, this may be considered a form of withholding:

The Subcommittee on Oversight and Investigations held three days of hearings last June regarding the reliability of American Gas Association reserve data. The principal witnesses were attorneys from the Federal Trade Commission's Bureau of Competition testifying on their investigation of the American Gas Association (AGA) natural gas reserve reporting system. They testified that AGA reserve data was substantially under-reported and that the AGA reporting system was seriously deficient. In subsequent testimony FTC economists challenged their findings.

Because of this division of opinion within the FTC and because the Bureau of Competition's conclusions were based on less than complete data, the Subcommitte on June 16, 1975, issued subpoenas *duces tecum* to seven gas producing companies and the AGA for natural gas reserve data for use by the Subcommittee in evaluating AGA reserve estimates of proved non-associated gas reserves.

Included among the documents subpoenaed from the AGA were individual field estimates for offshore South Louisiana for the years 1967 through 1974, as prepared by members of the AGA South Louisiana reserve subcommittee.

The AGA does not publicly report reserve information for individual fields. The AGA releases reserve data on a state or regional basis only. Offshore Gulf of Mexico, which includes reserves underlying both state and Federal waters, is only one of 48 regions for which the AGA reports reserves on an aggregate basis.

The best way to test the AGA reserve system is to compare AGA reserve estimates with those prepared by an independent party. Only within the past few weeks, however, has it been possible to make a meaningful comparison. The Subcommittee recently learned of and obtained copies of the U.S. Geological Survey's October 1974 and January 1976 Gulf of Mexico Federal outer continental shelf (OCS) reserve studies. These studies were described in hearings by the Subcommittee on January 21 by Dr. V. E. McKelvey, Director of the USGS and by the head of the Survey's reserve estimating unit.

It should be noted that the Survey did not compare its reserve estimates for the Federal OCS with those published by the AGA. The only AGA reserve data available to the Survey are the regional reserve totals for the 48 AGA areas published in the AGA's annual statement of proved reserves. AGA reserve estimates for the Federal OCS are not identified in those reports. Instead, they are aggregated for AGA reporting purposes with reserves underlying Louisiana and Texas state offshore waters. For that reason, the USGS has been unable to compare its reserve estimates with those of the AGA.

The AGA, meanwhile, due to the alleged proprietary nature of the Geological Survey's reserve studies, is not privy to the Survey's reserve estimates.

This Subcommittee, however, by virtue of its access to USGS reserve data and to its having subpoenaed AGA field estimates for offshore South Louisiana was in the position of being able to compare AGA reserve data with those of the USGS.

Prior to making this comparison, the Subcommittee staff engaged in detailed analysis to determine the comparability of the definitions employed by the AGA and the USGS. Were the Survey to have employed a broader, less restrictive definition of reserves than that used by the AGA, the issue would involve the reasonableness of the AGA reserve definition, as contrasted to that used by Interior Department geologists and engineers.

The Geological Survey speaks in terms of "measured reserves." The AGA uses the term "proved reserves." The question thus involves the similarity of the two terms. The Geological Survey and the Bureau of Mines have entered into what was described as a joint agreement "defining *resources* and *reserve* classification terms." A copy of that agreement was forwarded to all USGS conservation field offices with instructions from Dr. Russell G. Wayland, Chief of the Conservation Division of the USGS "to follow these definitions and terms in all our work, as applicable." That was on February 27, 1974, before the completion of the Survey's 220-field reserve study.

Page two of this inter-agency agreement contains a glossary of resource terms which notes that the terms "proved" reserves, as used by industry and "measured" reserves, as used by government, "are essentially synonymous." In a January 13, 1976, meeting with Subcommittee staff, Dr. McKelvey and other Geological Survey scientists, reiterated that measured reserves, as used by the USGS, are basically equivalent to "proved reserves," as employed by industry and the AGA.

In the hearing, the staff reviewed the comparison made by the Geological Survey and AGA reserve data.

The Survey's October 1974 year-end 1973, 220-field reserve study included all producing or qualified producing fields in the Federal OCS. The Subcommittee's subpoena for unpublished AGA reserve data did not include reserves in the offshore Texas area. The Subcommittee staff, therefore, in making its comparison deleted 17 fields located in offshore Texas Federal waters. Three fields partially in Louisiana state waters were also excluded because the USGS did not estimate those reserves. Forty-seven of

the remaining fields produce both associated and non-associated gas. Since the Survey did not differentiate between the two types of gas in its study, the Staff dropped those 47 fields from its sample in order to compare USGS non-associated reserve estimates with those of the AGA.

The Staff was left with a comparison that involved 153 pure gas fields located in Federal waters off Louisiana, which, according to the USGS, contain 67.4 percent of Federal OCS natural gas reserves.

The Staff totalled the USGS reserve estimates for those 153 fields for comparison with the corresponding year-end 1973 AGA total for the same fields. The USGS total came to 23.473 trillion cubic feet of gas. The AGA total was 14.704 trillion cubic feet. The AGA total was thus 8.769 trillion cubic feet or 37.4 percent less than that determined by the USGS.

To put those numbers into perspective, it's worth noting the requirements of Texas Eastern Pipeline, one of the largest and most severely undersupplied pipeline systems in the Nation. Texas Eastern sells some one trillion cubic feet of natural gas per year to heavy industrialized areas in New England, Ohio, and New Jersey. The 8.7 trillion cubic feet gap in AGA reserve estimates for the 153 fields in the Subcommittee staff study would satisfy all of Texas Eastern's needs for eight years. The Subcommittee has no basis for determining whether the AGA's nationwide reserve estimates are understated by the same 37.4 percent as reflected in the Subcommittee Staff comparison of AGA and USGS nonassociated reserve estimates for the South Louisiana Federal OCS. Were such a disparity to exist nationwide, however, the AGA reserve shortfall would amount to 102.7 trillion cubic feet of non-associated gas—enough gas to cover this winter's projected curtailments one hundred times over.

In rendering its 153 field comparison on the basis of the Geological Survey's October 1974 reserve study, the Subcommittee staff was aware of the Survey's January 1976 40-field update. In an October 1974 memorandum and the previously referred to January 1976 meeting with the Subcommittee staff, Floyd Bryan, the Survey reserve expert who headed up both Survey reserve studies, suggested that the October 1974 study was accurate within plus or minus 10 percent. The January 1976 reserve study, according to Mr. Bryan, is accurate within plus or minus five percent.

As a check, however, on the Survey's October 1974 study, the Subcommittee compared reserve estimates in the October 1974 study with those included in the January 1976 study. Due to the inclusion of new fields in the January 1976 study and a redefining of some of the fields included in the 220-field study, the Subcommittee was able to compare reserve estimates for 24 of the 40 fields. Those 24 fields were reported in the 1974 study as having 8.06 trillion cubic feet of proved reserves originally in place. The January 1976 study showed original reserves in place of 8.53 trillion cubic feet for these 24 fields. The more refined 1976 study resulted, therefore, in a 5.5 percent net increase in the Survey's October 1974

total estimates for these 24 fields. The Survey's October 1974 study, which forms the basis of the Subcommittee staff comparison, appears somewhat conservative in light of the Survey's subsequent work.

(c) If production from a lease has unaccountably fallen below minimum contract quantities, withholding may be occurring:

> Much of the curtailments predicted for the pipelines by FPC and FEA stems from the failure of gas producers to deliver the minimum quantities required under their contracts and certificates of public necessity and convenience and the failure of pipelines and the FPC to seek to enforce those obligations.
>
> For example, Gulf Oil Company's gas deliveries to Texas Eastern Gas Transmission Corporation in 1974 averaged only 393.2 million cubic feet (MMcf) per day, although their contracts specified that Gulf Oil would deliver 500 MMcf daily. Transcontinental Gas Pipeline (Transco), which predicted it would have severe curtailments this winter, has been receiving only one-third of the minimum daily contract quantities it is entitled to receive from 141 of its suppliers. This under-delivery to Transco amounts to 328.5 billion cubic feet (Bcf) per year, which is more than three-fourths of Transco's total projected deficiency of 429.3 Bcf for the 12-month period of April 1975 to March 1976. At the Energy and Power Subcommittee hearings on October 24, FPC's Deputy General Counsel, Robert W. Perdue, acknowledged that there were widespread breaches by numerous producers of their minimum daily contract commitments and that the FPC had not yet been able to obtain comprehensive figures on the specific nature of those breaches. Yet, no pipeline has ever taken a producer to court to enforce its contract and certificate obligations. One reason for the pipeline's failure to do so according to the testimony of Mr. Francis C. Allen, Chief of the FPC's Bureau of Natural Gas, at the October 24 hearing, is because "... the producer today in the gas shortage situation is in a very strong bargaining position and it may well be that the pipeline is afraid of some type of reprisal if they more vigorously seek enforcement of contracts ..."
>
> It would seem then that the FPC, which acknowledges it has the duty under the Natural Gas Act to insist that producers comply with their contract and certification obligations, should have sought to enforce those obligations. But the FPC has been very slow in enforcement efforts. It did not even announce its policy of enforcement until October 14, 1975. Furthermore, instead of ordering compliance or seeking a court injunction against a producer to comply with the delivery obligation, the FPC has initiated only the time-consuming procedure of asking a producer to "show cause" why it should not be required to meet contract commitments. Such procedure will result in considerable delay before the FPC issues its order, or seeks an injunction, requiring such compliance with delivery commitments.
>
> Instead of vigorously enforcing the Natural Gas Act, the FPC has dedicated itself to urging that the Natural Gas

Act's regulatory provisions be repealed to deregulate natural gas. The Energy and Power Subcommittee's hearings have shown that the FPC inadequately staffed its investigations of the producers' capabilities and contract obligations; that the FPC reassigned its investigatory staffs to work on policies designed to promote deregulation, and that the FPC did not hire needed experts to evaluate the complex and copious data it had concerning gas production records. It appears, therefore, that the commitment of the FPC Commissioners and its top staff to deregulate has gravely impaired the FPC's ability to conduct meaningful inveestigations and effective regulation of interstate natural gas as prescribed by the Natural Gas Act.

(f) If unduly large amounts of gas available in reservoirs are being retained for future sales under a contract, when current shortages are unsatisfied, withholding may be involved:

The FPC conducted an investigation of producible shut-in leases on Federal lands in Louisiana and Texas Outer Continental Shelf as of January 22, 1974. A producible shut-in lease is a lease upon which one well has been drilled and is determined to be capable of being produced in paying quantities and for which a suspension of production of operations has been approved by the USGS supervisor. The FPC staff investigation indicates that a total of 168 leases are classified as productible shut-in. Included in this total are 60 leases in their primary five-year terms, 96 leases in extended terms and 12 leases in exploration or production units.[9]

Of the total 168 leases in primary and extended terms and units, 40 are, according to FPC files, dedicated to interstate pipeline companies by gas purchase contracts, and 32 are committed by reason of advance payment agreements made between FPC regulated pipeline companies and the lessees. The 168 leases total 787,972 acres with bid bonuses totaling $1,490,716,000.[10]

During the primary term (the initial five-year period), there appears to be no requirement that the lease be on production or classified as producible shut-in.[11] There appears to be no requirement to put the lease on production (absent drainage from state lease production) or to seek a suspension of production or operations to obtain an extension prior to the end of the primary term. The lease operators apparently are not required to give reasons for seeking the producible shut-in classification.[12]

The three companies with the largest producible shut-in acreage in 1973 were Texaco, with 111,508 acres (34 leases), Chevron with 91,980 (24 leases), and Exxon with 53,544 (13 leases). In 1974, the three companies having the most acreage were Chevron with 109,337 acres (27 leases). Texaco

[9] Staff Report, Bureau of Natural Gas, Office of Economics, FPC, "Offshore Investigation: Producible Shut-in Leases as of January 1974," (First Phase), Wash., D.C., March 1974 at 1.
[10] Id. at 2.

with 107,955 (30 leases), and Union Oil with 51,514 (13 leases).[13]

Reserve estimates were made for each of the 168 leases classified by the USGS as producible shut-in as of January 22, 1974 in the second phase of the FPC's investigation. The FPC determined that the aproved reserves for leases in the primary terms (first five years) were 2.9 Tcf and that for leases in extended terms (over five years) the totals were 1.7 Tcf for a total of 4.7 Tcf.[14] The FPC determined that the probable reserves for leases in their primary term was 2.7 Tcf and for leases in extended terms (over five years) 5.1 Bcf for a total in the probable reserve category of 3.2 Tcf. The total of 4.7 Tcf for proved reserves from these producible shut-in leases is more than 20 percent of the Nation's annual natural gas consumption of 23 Tcf.

A separate FPC study indicated that reserves holding 8.5 trillion cubic feet in 1973 and 9.7 trillion cubic feet in 1974 were not producing any gas although they were dedicated to pipeline systems.[15] On March 14, 1975, the Department of the Interior, after a spot check of 17 leases, ordered three companies to begin production on three leases or risk losing them for lack of diligence.[16]

Natural gas producers maintain that the expenses incurred in bringing a lease to the point of production are so great that no producer could afford to forego the earliest possible return on that investment. They say that interest and inflation would reduce possible gains from delay in development to almost nothing.

Although producers claim that they could never afford to sit on such large investments without obtaining the earliest possible return, it should be remembered that the money used for oil and gas drilling is "risk money": money that is used with knowledge that it may be totally lost if dry holes are drilled. Having invested funds which they are prepared *never* to recover or achieve a return on, producers are obviously prepared to forego that return temporarily while speculating that the eventual recovery will be many times the price and profit gained from an immediate sale.[17]

Possible deregulation provides the incentive to withhold production and producers have the means to withhold because of lax enforcement of production requirements by the U.S. Government and the easy extension of a producing lease by payment of a nominal "delay rental." A recent survey by the National Aeronautics and Space Administration for the United States Geological Survey found that only about 10 percent of offshore leases are being produced, but that USGS does not have the personnel to enforce production requirements or the inclination after years of being concerned with safety and conservation of resources.

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[11] Id. at 8.
[12] Id. at 9.
[13] Id. at 18.
[14] Staff Report, Bureau of Natural Gas, Office of Economics, FPC, "Offshore Investigation: Producible Shut-in Leases as of January 1974," (Second Phase), Wash., D.C., July 1974 at 3.
[15] Bureau of Natural Gas, FPC, "Preliminary Investigation—Non-Production Gas Reserves in the Gulf of Mexico," Wash., D.C., February 1975.
[16] Gapay, Les, "Oil Firms To Be Told To Start Output Soon On 3 Federal Gas Leases or Lose Them," *Wall St. Journal*, March 14, 1975 at 4.
[17] Jimison Study, supra n. 3, at 21.

Even onshore, if there is no access to deregulated intrastate markets, withholding occurs through payment of small annual charges to landowners.[18]

Question 5. Would deregulation increase natural gas supplies enough to end the natural gas shortage?

Answer. Deregulation advocates acknowledge that even with deregulation, there is no guarantee that enough gas will be found to end the natural gas shortage. They say that without the certainty and incentive of free market pricing, the amount of natural gas found will be much less.

Gordon Zareski, Chief, Planning and Development Division, Bureau of Natural Gas of the Federal Power Commission, testified before the Energy and Power Subcommittee on January 27, 1976, that "we cannot expect price increases to provide the solution to declining gas production."

The lack of ability of natural gas producers to provide more gas at the prices which will prevail after deregulation was clearly documented earlier by the Project Independence Blueprint. According to this FEA report, the production of natural gas projected to result from a price of 80 cents per Mcf (19.114 Tcf in 1985) is virtually the same as the amount which would result from a price of $2.00 per Mcf (19.141 Tcf in 1985). The extra cost to consumers of deregulation of wellhead prices in 1985 alone will be $23 billion, assuming that 80 cents was the regulated price level, that deregulated prices were no higher than $2.00, and that old gas contracts had all expired.[19]

The history of recent years demonstrates that deregulation and higher prices are unlikely to elicit increased supplies. The FPC has increased producers' prices an average of 30 percent per year, far in excess of the rate of increase of inflation, yet reserve additions and commitments have continued to fall off. In each of its rate-setting proceedings, the FPC has been told the price set is the price necessary to stimulate the necessary exploration and development of natural gas to reverse the trend, and subsequently, the FPC is told the new rate is not enough.

Theoretically the natural gas which remains to be developed will *be* developed as long as the price allowed for it is sufficient to cover the costs incurred by the producer who finds it and provides a profit as well. The prices allowed by the FPC are set on that basis, and producers have had full opportunity to demonstrate to a sympathetic FPC that the prices resulting have been inadequate. They have been unable to demonstrate by evidence of costs or other evidence that the FPC's gas rates are non-remunerative. [20]

Question 6. Are the natural gas production and transportation markets competitive?

Answer. Dr. David Schwartz, formerly assistant chief of the Bureau of Economics of the FPC, has pointed out that, while the domination by the majors of the total gas production market may not seem overwhelming or uncompetitive (the eight largest companies control perhaps 42 percent of the market), that is not the relevant market.

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[18] Id. at 20.
[19] Federal Energy Administration, Project Independence Blueprint, Final Task Force Report—Natural Gas, November 1974, p. xii.
[20] Jimison Study, supra n. 3, at 15.

All gas is not resold each year; it is only the uncommitted gas which is up for sale. Here alone would true market competition operate. And here a few major companies control the market of the uncommitted reserves in major producing areas. The unavailability of verifiable reserve data for the relevant market prevents a complete analysis of this market influence. [21]

In the intrastate markets, where recent higher prices for national gas have put great pressure on the FPC to grant higher interstate prices, studies have shown that many of the major natural gas purchasers are affiliates of the natural gas producing companies.[22] It can hardly be argued that arms-length bargaining occurs between affiliates. Yet the intrastate market is constantly cited as an example of the kind of competition that could result from deregulation.

In the relevant market, the foregoing evidence suggests that the current structure of the industry significantly minimizes competition.

If the natural gas production and transportation markets are to be competitive enough to protect the consumers' interest, there must be effective arms-length bargaining between the parties to contracts for the sale of natural gas. Looking at the interests of the two parties to any gas contract, the producer and the pipeline, it becomes immediately clear why deregulation of this market would not produce a significant degree of competition.

The producer's entire interest in the sale is to obtain the highest possible initial wellhead price for the natural gas it dedicates to the pipeline. It will generally commit this gas to sale for twenty years or until exhaustion of the reservoir with likelihood of only minor annual adjustments in the price during the course of that period. Thus the producer determines its ultimate return with the initially agreed-upon price and knows that each one-cent raise in the beginning rate will result in additional millions of dollars over the life of the contract.

If the pipeline involved in the contract is as eager and as able to bargain for a lower price as the producer is to obtain a higher price, then perhaps effective arms-length bargaining could occur, protecting the consumer from unreasonably high prices.

The pipelines, however, to have little interest in seeking lower natural gas prices, for a number of reasons, and are thus willing to pay the producer the rate demanded. [23] Some of the reasons that pipelines cannot or will not bargain effective are:

1. The pipelines do not actually buy the gas—the consumers buy it. The pipelines contract for it, but the entire cost of the gas they purchase, at whatever price, is normally passed through to the consumer, often under "purchased gas adjustment clauses" which operate without regulatory oversight.

2. The pipelines are acutely aware that natural gas is a non-replenishable resource. Since they make money as a return on their facilities, not as a "mark-up" on gas prices, the longer they can continue to use those facilities the better off they will

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[21] Schwartz, Dr. David S., Assistant Chief, Office of Economics, FPC, Statement to the Senate Commerce Committee, Consumer Energy Act, v. i. p. 215.

[22] Donkin, George L. "The Competitive Effects of Interdependent Actions Among Buyers and Sellers in the National Gas Producing Industry," Cornell Energy Study. Reprinted in Hearings on Consumer Energy Act, Senate Commerce Committee, v. 5, p. 2056.

[23] Jimison Study, supra n. 3, at 30.

be. Thus, the pipeline's dominant interest is to obtain the commitment of the gas to its system whatever the price.

3. The pipelines have large volumes of relatively low-priced flowing gas with which to "roll-in" the prices they pay for new gas. Consumers' prices will increase only a small amount initially from the extremely high prices pipelines will pay for incremental supplies, but the increase will be continuous and inexorable. Of course, to the extent that this old, flowing gas is also deregulated, consumers prices will jump immediately. Nonetheless, the ability to average in the cost of new gas with all the old gas removes a significant incentive for pipelines to bargain for lower prices.

4. The pipelines have begun to plan for enormous investments in coal gasification and liquefied natural gas to supplement their declining natural gas supplies. These projects are now projected to cost from $2.50 to $4.00 per Mcf, compared to the present natural gas average of 32 cents per Mcf. Since pipelines realize that major additions to their pipeline networks will not be justified during the shortage, their corporate growth as a result of investment (and thus their profits as a return on that investment) would be stymied without such projects for substitute supplies as the planned capital-intensive LNG and SNG facilities. Yet these facilities themselves are not feasible at current gas prices. The much higher natural gas prices that would follow deregulation would make the pipelines' planned investments in SNG and LNG more acceptable to regulatory agencies and the public. It would seem irrational for the pipelines to undercut the economic viability of such projects by vigorously bargaining for the lowest possible natural gas prices.

All the major interstate pipelines have subsidiaries engaged in gas production. In purchasing gas from itself, a pipeline will pay the highest rate it can, because the rate is passed through to consumers. The general increase in gas market prices that will result from pipelines paying higher prices to any supplier will benefit the pipeline's own subsidiary. Pipelines can hardly be expected to bargaining vigorously for lower gas prices, since the higher the average level of wellhead prices, the greater the profits of their production subsidiaries.

6. Finally, the pipelines are fully aware that consumers will accept higher natural gas prices until they equal the price of alternate fuels or are even higher because of the costs of conversion. No consumer will convert to another fuel unless gas becomes at least as expensive. With alternate fuels averaging in excess of $2.00 per million Btu's while gas is 32 cents per million Btu, there is a great deal of room for upward adjustment before any gas customers shift to competing fuels. No pipeline will try to bargain for lower prices when higher prices will not drive customers away and bargaining will alienate the producers.

For these reasons and others, pipelines will have no incentive to counter the strong producer incentive for higher prices. The producers in a deregulated market will charge what the traffic will bear, and consumers will pay the producers via pipeline rates—a price over which the ultimate consumer has no control.

Deregulation would remove the remaining regulatory checks on this structurally and functionally uncompetitive market, to the great detriment of the Nation's consumers. [24]

Question 7. Would deregulation be expensive to consumers?

Answer. The Economics Division of the Library of Congress recently published an analysis of the Pearson-Bentsen bill, S. 2310 as amended by the Senate, which provides for the phase-out of natural gas price controls on "new" gas by January 1, 1981. New gas is defined as (a) gas entering interstate commerce for the first time (after January 1, 1975) and (b) produced from new fields discovered after January 1, 1975. Under this proposal, gas in the Outer Continental Shelf would remain under price controls until January 1, 1981. However, the FPC is directed to authorize a new rate for OCS gas, and in the interim, this gas would be permitted to sell for the Btu equivalent price of OCS crude oil, an estimated $1.60 per Mcf.

Currently, the average price paid by FPC jurisdictional pipelines for natural gas is 35.5 cents per Mcf based on a hierarchy of rates for various vintages, one of which is "new" gas at 52 cents per Mcf, which in practice averages 55 cents per Mcf due to various adjustments. Intrastate gas sells for an *estimated* average price of $1.25 per Mcf.

H.R. 10480, as introduced by Congressman Krueger, contains a slightly different definition of "new" gas, but the Library of Congress states that these definitional differences do not measurably affect the cost calculations performed by Library of Congress analyst in energy economics, Lawrence Kumins, on the various provisions of S. 2310.

The Pearson-Bentsen bill proposes a market clearing price for gas based on Btu equivalency with OPEC oil based fuels.

Assuming that future oil prices remain high and that demand for natural gas does not decline in the years ahead, the cost of deregulation in terms of wellhead prices by the end of 1976 would be at least $20.3 billion and could go as high as $22.4 billion if the FPC fails to enforce contract deliverability, Kumins calculates. He allows for the most optimistic assumption about reserve additions that might result from deregulation. Let's assume, he says, that reserve additions average 25 Tcf for the next several years in lower 48 states and OCS areas. This is the highest level of reserve additions achieved in any one year (1956) in the U.S. and never again equaled. If this is achieved for 3 consecutive years, production may be able to increase just over 3 Tcf per year—from a current level of 21.6 Tcf to 25 Tcf. Kumins calculates that the incremental cost of this extra 3 Tcf will be about $6.75–$7.45 per Mcf, obtained by dividing $20.3–$22.4 billion by 3 Tcf.

Without rigid contract enforcement, the $14.9 billion figure in the $12.8–$14.9 billion range will escalate $2.1 billion each year. And expiring contracts will add an additional $1.9 billion. By the year 1980 or 1981, when most of what is now interstate gas will be free of regulation, gas consumers will pay between $20.4 billion to $30.9 billion extra in that year even if no extra supply is elicited.

Says Kumins, the near-term economic impact of 1976 price increases of $12.8–$14.9 billion in an economy with an annual GNP of approproximately $1.6 trillion will be to add 8/10th to 9/10th of a percentage

[24] Jimison Study, supra n. 3, at 33.

point to the inflation rate. He believes that ripple effects could expand this by at least 50 percent, causing the 1976 inflationary impact to be 1.2 to 1.4 percentage points. This would translate into the loss of several hundred thousand jobs.[25]

A recently published General Accounting Office reports that the average residential gas consumer will pay $94 more a year for gas in 1980 if Congress deregulates.[26]

GAO estimates the cumulative costs for the 10 years ending in 1985 at $75 billion—an increase of 22 percent over the cumulative city-gate costs of gas with continued regulation.[27]

GAO concludes that under continued regulation at or near current prices, natural gas supplies in 1985 would be about 17 Tcf—20 percent below 1975 supplies, and that deregulation would produce only an additional 2 Tcf—or supplies at a level 13 percent below 1975 levels at 19 Tcf.[28] Kumins and David Schwartz, formerly the second-ranking FPC economist, calculate the cost of each 1,000 cubic feet in this increment to be $5 to $10—the Btu equivalent of $30 to $60 for a barrel of oil.

Deregulation would increase producer gross revenues from an estimated $9 billion in 1975 to $31 billion in 1980, the GAO study says.[29]

Deregulation will not end curtailments, and there is no justification for such windfall profits for producers. There is no reason, therefore, to allow the natural gas industry to stampede Congress into passing such a costly and ineffective measure.

Question 8. Will natural gas producers have adequate incentive without deregulation?

Answer. The regulated rates set by the FPC are stated to contain a 15 percent rate of return on the rate base or almost 18 percent return on equity. Producers maintain that the full cost of producing natural gas is not included in the formula to which the 15 percent return is applied, that the averaging of the costs from wide areas rules out drilling for higher than average cost prospects, and that the use of historical test-year cost data does not account for the inflation prevalent throughout our economy and particularly severe in the oil and gas drilling industry.[30]

There has been an attack by the industry on the use in regulation of their prices for natural gas of evidence relating to the costs of natural gas production. Yet cost of production data is obviously the key for the determination of just and reasonable prices. Before the general energy crisis, OPEC monopoly pricing, and gas shortage allowed partial or complete deregulation to become a political possibility, the industry's campaign for higher prices in Congress revolved around amendments to the Natural Gas Act which would have required the FPC to consider, when setting prices, evidence of the prices of alternate fuels (Btu equivalents), the premium fuel characteristics and environmental desirability of natural gas, and other so-called market factors.

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[25] Kumins, Lawrence. "Economic Impact of S. 2310's Pricing Provisions." Library of Congress Congressional Research Service. December 31, 1975, at CRS 2-13.

[26] Comptroller General of the United States. "Implications of Deregulating the Price of Natural Gas." Report to the Committee on Government Operations, House of Representatives. January 14, 1976 at 57.

[27] Id. at vi.

[28] Id. at 56.

[29] Id. at 56.

[30] Jimison Study, supra n. 3, at 42.

These past proposals would have forbidden the FPC to look into the producers' actual costs.[31]

The FPC, in its rate-setting, calculates all the costs associated with exploration, development, and production of natural gas: lease acquisition costs, exploration, overhead expenses and other production costs, dry holes, taxes, and royalties. Producers have not been able to suggest to the FPC other factors that should be considered that are not considered now. The FPC even provides a rate relief procedure for special cases—producers whose costs exceed average costs for the industry. Still, producers argue that the price is too low. It is interesting to note that the producers do not criticize the FPC rate formula because it excludes legitimate costs; rather, they take issue with the method by which the FPC determines such costs. Whereas the FPC attempts to measure actual outlays, some producers propose various ways of measuring costs which have the effect of inflating actual expenditures.

In arriving at its December 1975 price decision, the FPC accepted the producers' contention that a discounted cash flow analysis should be used to calculate the rate of return and raised the price to 55 cents per Mcf, including allowables. Over the last few years, FPC Commissioners have supported deregulation. Yet try as it might, the Commission apparently could not justify a price higher than 55 cents.[32]

Revenues in excess of all the costs of producing natural gas, including capital outlays and an almost 18 percent return on equity, are considered by economists to be windfall profits. If 55 cents per Mcf provides a 15 percent return on the rate base, 75 cents per Mcf will provide profits (total revenues less total costs) of between 50 percent and 100 percent.[33] Deregulated process of $2.00 per Mcf or more would result in a massive redistribution of wealth.

If the natural gas producing industry is as competitive as it claims to be, and if additional efforts on its part can resolve the natural gas shortage, as it says it can, those efforts, one would suppose, would be forthcoming at the highest price the industry itself can justify based on its actual experience of cost and need. Recently the Commission has done its best to permit the industry to receive that price, accepting the industry's contention time after time that more incentive is needed to reverse the shortage. But the discouraging trends continue, and the shortage worsens. If we disregard this experience and once again give the industry all it claims to need, we can expect no better.

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[31] Id. at 46.
[32] Federal Power Commission, Docket R. 389–B, Opinion 699–H, Opinion and Order on Rehearing, issued Dec. 4, 1974.
[33] Jimison Study, supra n. 3, at 48.

Appendix A

Departmental Correspondence, January 26, 1973

To: D. W. Keller.
From: W. S. Hawkins.
Re Alice C. Plantation No. 2, MA–9A Recompletion Prospect, Garden City Field, La.

The Alice C. Plantation No. 2 was completed and abandoned in the MA–7 sand, and is presently unable to buck line pressure in the MA–5 sand. All attempts to improve the MA–5 completion have been unsuccessful. The MA–9A sand is the only recompletion prospect remaining in the well.

The MA–9A sand has never been tested in the Garden City Field. The productive portion of the sand, as mapped, has an areal extent of 448 acres and an average thickness of 6.25 feet. *Gas-in-place is estimated to be 7.62 BCF by volumetric methods.* The apparently poor sand conditions in some wells make ultimate recovery and deliverability the primary risks in the project.

The Alice C. Plantation No. 2 is at the optimum location for a MA–9A test and the well bore is in good condition due to the recent workover (Oct. and Nov. 1972). A 5″ tieback string was run and the production tubing was replaced during that workover. The Invermul completion fluid that was used, should maintain the well bore in good shape for a workover at a later date.

Since the MA–9A reserves are uncommitted and the price free to rise, it is recommended that this project be deferred indefinitely until a higher gas price better justifies the risk involved.[6]

Enclosures.

Alice C. Plantation No. 2, MA–9A Sand Prospect, Garden City Field

Reservoir Volume:	*Areal extent (acre)*
Net pay isopach interval:	
0 to 5 ft	158
5 ft to 10 ft	199
10 ft	91

Productive Bulk Volume = 2.5 × 158 acre = 395 acre feet.
5.0′ × 199 acre = 1,493 acre feet.
10.0′ × 91 acre = 910 acre feet.
= 2,798 acre feet.

Assumed Reservoir Properties:

Porosity: 22 percent (from Alice No. 4 sonic log).
Initial Pressure: 12,900 psi.
Temperature: 734° R.
$\geq$: 1.60.
Bg_2: 0.470 res.bbl./mcf.
Water saturation: 25 percent.

Reserve Estimates:

G–I–P = (7758 × .22 × .75) ÷ .47.
= 2723 mcf/acre feet.
Total G–I–P = 2723 mc = /acre feet × 2798 acre feet.
= 7.619 bcf.
Recoverable reserves at 60 percent recovery = 4.571 bcf.
Recoverable reserves at 70 percent recovery = 5.333 bcf.

[6] Emphasis added. Not in original.

Appendix B

[Getty Oil Company]

Industry Outlook Series, 1975

INTRODUCTION

What the IOS Is

The Industry Outlook Series (IOS) is designed to be a coordinated set of long range forecasts which provides a consistent base for establishing division and operating group planning and investment evaluation premises. The IOS itself does not represent an "official" set of planning or evaluation premises, but rather a continually evolving background against which approved premises may be set.

In preparing the IOS, most of the attention has gone toward premises which are currently important to Company investment plans and operations. Areas of attention are subject to change and will be modified as investment opportunities present themselves and as overall strategy evolves. Where possible, the forecasts presented stem from original research and development. Otherwise, due to a lack of specific expertise or due to time constraints, outside studies have been distilled and adjusted to fit the overall IOS frame of reference. In some cases, Corporate Financial Planning has relied heavily on division and operating group personnel for guidance in analysis.

How to Use the IOS

As a background for establishing consistent planning and investment evaluation premises, the IOS should be viewed in its entirety including the written material. Considerable deliberation has gone into presenting each forecast in a manner which lends itself to relatively unbiased comparisons when price and cost premises play an important role.

All of the forecasts are presented on a current year or nominal dollar basis. That is, the premises shown in graphical displays represent the actual prices and costs expected for given years. As such, each price schedule includes real supply and demand related price movements compounded by the overall tendency for prices to increase due to inflation. The impact of inflation which is included in all of these premises, as well as in the current minimum return standard, is represented by changes in the Consumer Price Index schedule. In addition to the current year dollar data, constant or real dollar data for the beginning of 1975 and 1976 are included where meaningful.

The single most likely view of inflation is included in the high and low forecasts, as well as most likely views. This allows the current minimum return standard to be applied directly to high and low cases without adjustments associated with varying inflation forecasts. In addition, this approach highlights the factors having a specific impact on high and low forecasts.

The most likely views represent the single prices or costs which have the best chance of actually appearing in any given year. The highs and lows are designed to cover a 90% confidence interval, which captures the actual value (subject to the single inflation view provision noted above) 9 out of 10 times. This means that if inflation is as projected in the most likely forecast, the actual price in any given year will be below the low 5% of the time and above the high 5% of the time.

All of the data included are averages for the given year. As a calculation convenience it may be assumed that yearly averages are synonymous with values occurring at midyear. Under this approach, values for specific dates, such as the beginning of the year, may be found by interpolation. The necessity for these calculations could arise where indices of future changes are applied to known data. In such cases, it is important that the index used to project midyear values be stated on a consistent basis with the known starting point.

The Overall Outlook

The general economic outlook for the next ten years is a combination of lower real growth and higher inflation than for any decade since the Korean War. Overall economic growth in terms of constant dollar GNP is expected to average around 3.0% per year, which is less than the 3.5% experienced over the last thirty years. The general level of prices as measured by the Consumer Price Index is expected to increase at an average annual rate of 5%. This compares with about a 1.5% rate experienced during the 1958–67 period.

For the near term, contrary to the most common current opinion, we expect the recession to continue well into the second half of this year. The expected turn-around will begin as a gradual change in direction late in the fourth quarter. The comparatively restrictive growth in the money supply over the past six quarters, coupled with a weak economy in general, is expected to exert a restraining influence on the rate of inflation this year and next.

After 1976, however, another round of high inflation stemming from over reaction to the current recession is anticipated. That is, the Fed may be forced by political pressure to drastically increase the rate of growth in the money supply, and Congress may enact a number of fiscal programs which somehow will become permanently engrained in the budget. So, instead of combating a weak economy, the anti-recessionary policies actually end up adding fuel to the next upward leg of the business cycle.

In addition to these general trends, the economy will be going through a transition period with respect to energy consumption over the next decade. The structural relationships which have evolved through 1973 as a result of cheap energy will be realigned. Those industries built on low energy costs will find themselves at a comparative disadvantage and over time will change their methods of operation and experience reduced output. Personal consumption patterns, which are continually changing, will move away from areas of high energy use into other channels. Some of the results to be expected as this transition moves ahead are a shift away from larger, high gas consuming automobiles, greater dependence on rail transport, more insulation and less window glass in new construction, and reduced growth or a decline in general recreational enterprises.

These kinds of changes are to be expected if high energy costs for the U.S. prevail, i.e., if OPEC control remains as tight as is expected. The manner in which the structural changes are allowed to evolve is another matter entirely. The government may continue to forestall, guide, and direct the adjustment process, and to the extent that such intervention is contrary to market forces, misallocation, inefficiencies, and waste will occur. The best example of such misguided direction is the continued control of natural gas prices and the resulting shortages in the industry today.

For the petroleum industry, the general profitability outlook in the coming decade is improved when compared with the 1960's and early 1970's. As a result of OPEC control over world oil prices, the value of domestic crude has risen substantially, even after expected taxes. It further appears that the U.S. government, in an effort to encourage alternate energy sources, may support high crude prices in the event OPEC control collapses. Given the current lowered view of growth in energy consumption and higher crude costs, refining operations in the forseeable future appear marginal at best. Petrochemical operations, on the other hand, are less sensitive to crude costs and still appear attractive.

Government Actions

Government intervention by way of tax reforms and various direct controls may be expected from time to time throughout the economy. In the general energy area, the following events and policies are expected to emerge over the next two to four years:

1. Coal development for electric power generation and gasification will be mandated.
2. For synfuels, such as shale oil, a floor price will be established to promote and guarantee the start of a viable industry.
3. Nuclear power growth will continue on the present restricted basis until the early 1980's.

4. Conservation of energy use will be promoted through taxation and legislation, including:

a. Gasoline taxes and excise taxes on inefficient automobiles.

b. Tax credits for energy-saving improvements such as home insulation.

c. Legislation to establish energy-saving standards in building construction and for appliances.

Much of the government involvement is likely to have a direct impact on the petroleum industry and on forecasts presented here. The most likely views include these specific government actions.

1. The "old" and "exempt" production categories for price regulation will be abandoned and replaced by a windfall profits tax without plowback provisions applied to all crude sales.

2. The supplemental import tariff of $1 per barrel of crude oil will last indefinitely, but will not be increased.

3. FEA regulation of manufacturing operations will continue in effect until 1977.

4. FPC control of natural gas prices will persist indefinitely, although rates will be allowed to rise much faster than they have in the past. This will not prevent, however, natural gas shortages from reaching crisis proportions.

NATURAL GAS PRICES

The natural gas price (rate) forecasts which follow are of two types; either relating to contracts which require periodic rate calculations, or pertaining to new sale arrangements. California border prices are those which Getty Oil Company will receive under existing contracts with California public utilities. California call gas prices reflect newly negotiated terms for peak load periods. New interstate prices are for new contracts which are currently under Federal Power Commission (FPC) control, i.e., those involving interstate transport of gas.

All of the natural gas price forecasts were based on a review of economic factors modified by various scenarios concerning the level of government intervention. The general outlook for natural gas is one of increasing shortages. "Free Market" values, for analytical purposes, are assumed to be somewhat above the Btu equivalent market price for crude oil. Such premium is related to lower costs associated with transportation and burning characteristics of natural gas. In formulating views of political intervention, consideration was given to the possibilities for continued FPC regulation along the lines of announced schedules, less severe FPC controls, and "windfall profits" taxes for natural gas sales.

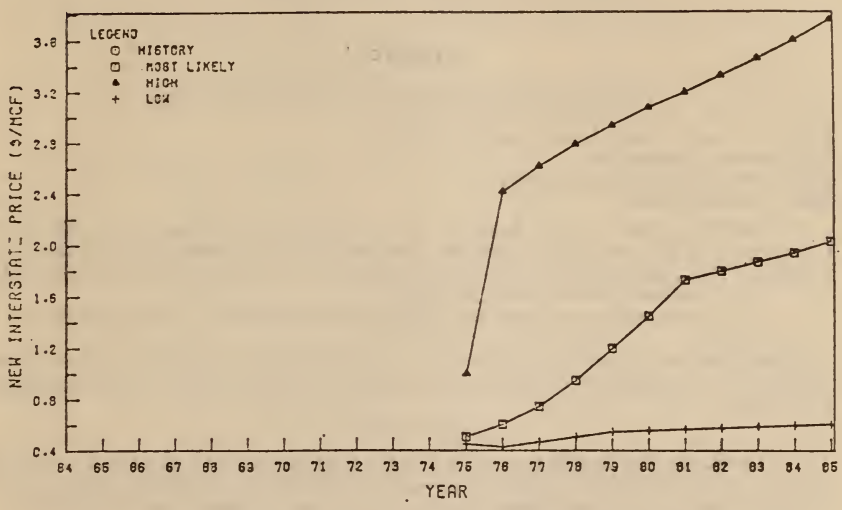
The most likely view of new interstate prices incorporates continued control from the FPC, however, rates are allowed to rise faster than the current FPC increase schedule. By 1981, prices rise to a level which is equivalent on a Btu basis with most likely "net", or after a windfall profit tax, crude oil prices. These 1981 and beyond prices still include a degree of political control, since in the absence of controls we would normally expect the price to be above the "gross", or before windfall profits tax, crude price.

Under the contract terms with California utilities, border prices are an average of the prices paid by the utilities including transportation to the California border. The most likely view for these prices is based on an average of old contract prices being paid by the utilities and most likely new interstate rates plus transportation from the Gulf Coast. The new interstate price portion of this average increases from about 75% to 100% by 1985. Most likely call gas prices are border prices plus a 35% premium which lasts until 1980, then the price less transportation reaches a Btu equivalent with crude oil market values.

The high views are based on a scenario of complete deregulation of all (new and old) interstate natural gas prices next year, plus high crude oil prices. New interstate rates are calculated at a 10% premium over the Btu equivalent of high domestic crude prices. Border prices are these new interstate prices plus transportation. Call gas prices include a 10% premium over high border prices.

The low view incorporates a very restrictive political control scenario represented by the FPC's current schedule of increases for new interstate prices.

NEW INTERSTATE NAT. GAS PRICES



SELECTED GROWTH RATES AVERAGE %/YEAR

	64-69	68-73	70-75	75-85	AFTER 85
MOST LIKELY				14.81	5.00
HIGH				14.16	5.00
LOW				3.09	5.00

NEW INTERSTATE NATURAL GAS PRICES

[In dollars per thousand cubic feet]

	1964	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974
Current year:											
History											
	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Forecast:											
Most likely	0.51	0.61	0.75	0.95	1.20	1.45	1.73	1.80	1.87	1.94	2.03
High	1.00	2.42	2.62	2.79	2.94	3.08	3.20	3.33	3.46	3.60	3.76
Low	.45	.43	.47	.51	.55	.56	.57	.58	.59	.60	.61
Constant Jan. 1, 1975:											
Forecast:											
Most likely	.50	.57	.64	.76	.92	1.06	1.21	1.21	1.21	1.22	1.21
High	.97	2.25	2.24	2.25	2.25	2.25	2.24	2.25	2.24	2.25	2.24
Low	.44	.40	.40	.41	.42	.41	.40	.39	.38	.37	.36
Constant Jan. 1, 1976:											
Forecast:											
Most likely	.52	.60	.68	.81	.97	1.11	1.28	1.28	1.28	1.27	1.28
* High	1.02	2.37	2.36	2.37	2.37	2.37	2.36	2.36	2.36	2.36	2.36
Low	.46	.42	.42	.43	.44	.43	.42	.41	.40	.39	.38

* Projected price increases in constant dollars in the event of deregulation.

Appendix C

Inter-Office Correspondence—Getty Oil Co.

Subject: Bastian Bay Field Depletion Study.
To: Mr. O. G. Gage, Jr.
From: Production—New Orleans.
Date: June 12, 1974.

A depletion study of the Bastian Bay Field has been made using Getty Oil Company's M–55 computer program, and gas in place calculated by the M–28 program. The purpose of this depletion study was to predict gas production with:

(1) Wellhead pressure of 1,115 psia.

(2) Compression installation during 1974 to reduce wellhead pressure to 485 psia.

Minor reserves in presently undeveloped and/or nearly depleted sands were not considered. Availabiiity of wellbores for these reserves could not be accurately predicted.

CONCLUSIONS

(1) Predicted gas production from the Bastian Bay Field will be 385 BCF from January 1, 1974 if wellhead pressure remains at 1,115 psia. If wellhead pressure is reduced to 485 psia, then 606 BCF will be recovered, an addition of 221 BCF.

(2) Immediate production rate increase will be 37 mmcfd.

(3) Predicted production to 485 psia wellhead pressure and D&M estimate of gross remaining reserves compare favorably.

	BCF
Getty Oil's M–55 computer prediction	606
D. & M. GRR	517

(4) *The R RA SU, S RA SU and X RB SU should be depleted at an accelerated rate.* [Emphasis supplied.]

RECOMMENDATIONS

(1) Install compression in the Bastian Bay Field as soon as practical.

(2) *Study the R RA SU, S RA SU and X RB SU reservoirs to determine the additional wells needed for accelerated depletion.* [Emphasis supplied.]

DISCUSSION

Getty Oil Company's M–55 computer program was used to predict future Bastian Bay Field performance. Gas in place estimates utilized in the M–55 program were taken from the Bastian Bay Reserve Review dated January 11, 1974. Predicted bottom hole pressures were in good agreement with the exception of the O sand FB A reservoir. It was necessary to cut the M–28 derived gas in place for this reservoir from 541 BCF to 467 BCF to match the actual bottom hole pressure trend.

Many of the reservoirs in the Bastian Bay Field are comprised of several separate sand members that are not connected. Due to this fact, bottom hole pressures are sometimes different in wells completed in the same unit. Since this condition exists, precise predictions utilizing Getty Oil Company's M–28 and M–55 programs are impossible; however, it is felt that overall accuracy is sufficient to accomplish the purpose of this study. The M–55 program was run on all presently producing gas reservoirs in the field. It was not run on reservoirs with minor reserves and no present producers.

A 485 psia wellhead pressure and a 400 mcfpd average well cut-off rate were assumed. *All gas reservoirs will be depleted within ten years or less with the exception of the following:* [Emphasis supplied]

(1) R RA SU—There are three wells producing from this reservoir. *Depletion will require 20 years even with compression. Rate well economics for this reservoir will be studied.* [Emphasis supplied.]

(2) S RA SU—The S sand FB A reservoir is cut by a major north-south fault. The S sand has several hundred feet of gross section. A 100' fault separates it into two reservoirs. The east side of the fault is downthrown. The reservoir contains seven wells.

There are no wells producing from the west or upthrown side. One well is being drilled (Tenneco's LL&E "A" No. 29) to evaluate a portion of the west side of the S RA SU. If this well is successful, then other wells will be drilled to this reservoir.

(3) X RB SU—Depletion of this reservoir was based on two wells. AFE's to recomplete two additional wells to the X RB SU have been sent to Tenneco for approval. *If two workovers are successful, then this reservoir will be depleted at an accelerated rate.* [Emphasis supplied.]

A comparison of the M–55 predicted reserves with Getty Oil Company Book Reserves and D&M calculated reserves is attached. The predicted reserves are 9.2% lower than 1–1–74 Book Reserves and 14.7% higher than 1–1–74 GDRR carried by D&M. As previously mentioned, the M–55 reserve prediction cannot be considered precise. The favorable comparison with D&M reserves indicates that the program is sufficiently accurate to determine a reasonable estimate of additional gas that can be recovered from lowering wellhead pressure from 1,115 psia to 485 psia. When compression is installed, it will be necessary to revamp flowline and header system to achieve minimum pressure drop from the wellhead to compressor suction.

Total field production history, predicted gross cumulative gas production at 1,115 and 485 psia wellhead pressures, and predicted gross gas production rates are shown in the attached graph. Performance curves for each sand are in the New Orleans District files.

Computer print outs showing predicted reservoir performance for individual sands are also attached. It is planned to use this study to continue monitoring depletion of the field.

B. W. Cato.

Attachments.

BASTIAN BAY RESERVE COMPARISON, JAN. 1, 1974

[Legend: SUE=Sand Unit East; SUW=Sand Unit West; SUT=Sand Unit Total; XX=No wells producing in reservoir]

Sand Unit	M–55 prediction 485 p.s.i.a., Jan. 1, 1974 GDRR (BCF)	Getty Book reserves, Jan. 1, 1974 GDRR (BCF)	D. & M. January 1, 1974 GDR (BCF)
BBA M RA SU	4.96	2.5	1.39
BBA N RA SU XX	(1)		
BBA O RA SU	157.0	200.0	180.3
BBA O RB SU			
Total O sand	157.0	200.0	180.3
BBA R RA SUE	(2)	(2)	(2)
BBA R RA SUW	59.8	(3)	(3)
R RA SUT total	59.8	34.6	52.2
BBA R RB SU	15.0	18.8	17.6
Total R sand	74.8	53.4	69.8
BBA S RA SUE	128.0	(3)	(3)
BBA S RA SUW	51.2	(3)	(3)
S RA SUT total	179.2	156.0	106.0
BBA S RB SU XX	(1)		
Total S sand	179.2	156.0	106.0
BBA V RA SU XX	(1)		

See footnotes at end of table.

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BASTIAN BAY RESERVE COMPARISON, JAN. 1, 1974—Continued

[Legend: SUE=Sand Unit East; SUW=Sand Unit West; SUT=Sand Unit Total; XX=No wells producing in reservoir]

Sand Unit	M-55 prediction 485 p.s.i.a., Jan. 1, 1974 GDRR (BCF)	Getty Book reserves, Jan. 1, 1974 GDRR (BCF)	D. & M. January 1, 1974 GDR (BCF)
BBA W RA SUE	(3)	(2)	(2)
BBA W RA SUW	(1)		
BBA W RA total	(1)		
BBA W RB SU	5.6	3.3	2.8
Total W sand	5.6	3.3	2.8
BBA X RA SUE	26.6	(3)	(3)
BBA X RA SUW	84.8	(3)	(3)
X RA total	111.4	178.0	127.7
BBA X RB SU	73.3	74.6	29.1
Total X sand	184.7	252.6	156.8
Total field	606.26	667.8	517.09

[1] Not included in depletion study.
[2] Depleted.
[3] Not differentiated by separate reservoirs.